ACCESSION #: 9108280249
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Oconee Nuclear Station, Unit 3 PAGE: 1 OF 11

DOCKET NUMBER: 05000287

TITLE: Equipment Failure While Performing Testing Results in Control Rod Group Drop and Subsequent Automatic Reactor Trip
EVENT DATE: 06/09/91 LER #: 91-006-01 REPORT DATE: 08/15/91

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv) & OTHER: 50.72(b)(2)(ii)

LICENSEE CONTACT FOR THIS LER:
NAME: Henry R. Lowery, Chairman, TELEPHONE: (803) 885-3035
Oconee Safety Review Group

COMPONENT FAILURE DESCRIPTION:
CAUSE: F SYSTEM: AA COMPONENT: X15 MANUFACTURER: E155
REPORTABLE NPRDS: Yes

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On June 9, 1991, with unit 3 at 100 percent full power, a Control Rod Drive (CRD) system verification test required by Technical Specifications was being performed. At 1506 hours, after transferring a single control rod in Group 5 to its auxiliary power supply, the entire rod group fell into the core. Reactor power dropped to approximately 30 percent full power prior to a reactor trip three seconds later on low pressure/temperature ratio. The plant post-trip response was normal. The unit was stabilized at hot shutdown conditions. The root cause of the event was found to be equipment malfunction: a failed transfer switch allowed the normal and alternate CRD power supplies to simultaneously energize the Group 5 CRD mechanisms. The failed transfer switch was replaced. Further investigations are centered around the history of the transfer switch, methods to prevent its failure, and methods to give the operator indication when power supply transfer failures occur.

END OF ABSTRACT

BACKGROUND

The Unit 3 core (EIIS:AC) has 69 control rods [EIIS:ROD] divided into eight groups. Groups 1 through 4 are used to provide safe shutdown capability and are placed in the full out position when the reactor is critical. Groups 5 through 7 are regulating rods and are used to control reactor power. Group 5 has twelve rods. The control rod drive mechanisms (CRDM) [EIIS:AA] use a six-phase, DC stator to raise or lower a lead screw which is coupled to an individual control rod. Two phases of the stator are normally energized to hold a control rod in a fixed position. When the stator is deenergized, the rod will drop. To move a control rod, the six phases of the CRDM stator must be sequentially energized. This is accomplished by using a digital programmer to vary the gate voltage on silicon controlled rectifiers placed in the power supply circuit.

There are two power supplies [EIIS:AA] to the regulating groups, the normal power supply and the auxiliary power supply. The normal power supply, as its name implies, will normally be used to hold the rods in place and to move them when a rod motion signal is received. The auxiliary power supply serves as a backup. It can also be used to move individual rods in a group while the other rods are being held by their normal power supply. Each power supply contains its own programmer and rectifiers to produce rod motion. Each CRDM has a transfer switch which simultaneously transfers all phases of that CRDM from one power supply to another. These transfer switches are six pole, rotary power switches with make-before-break contacts and are controlled by a 120 millisecond pulse input.

The CRD patch panels [EIIS:AA] are panels with connections which allow any CRDM to be assigned to Groups 1 through 7. This is done by exchanging instrumentation leads associated with those CRDMs. Technical Specification 4.7.2.1 requires that after the patch panel is locked following maintenance a complete verification shall be performed by exercising each rod individually.

EVENT DESCRIPTION

On June 8, 1991, with Unit 3 at 100 percent full power, Instrument and Electrical (I&E) personnel began investigation into a problem with the Absolute Position Indication (API) for control rod 5 in safety group 4 of the control rod drive (CRD) system [EIIS:AA]. This problem was causing an asymmetric rod alarm to occur. During this maintenance, two fuses to the API meter for Group 4 Rod 5 were blown in the control rod drive patch panel. Administrative procedures require approval from the Station Manager prior to unlocking and opening the patch panels. This approval was obtained, the patch panels were opened, and the fuses replaced. Technical Specification 4.7.2.1 requires a patch panel verification be performed after the patch panel is locked. Steps were initiated to perform this task on June 9, 1991. I&E personnel completed a check of the CRD system power

supplies using IP/0/B/340/02, "Control Rod Drive DC Hold Power supply Check" at 1128 hours.

At 1137 hours, Reactor Operators (RO) placed Integrated Control System (ICS) [EIIS:JB] stations in manual. This action placed feedwater [EIIS:SJ] flow and rod position in manual control. This was necessary to allow the performance of the patch panel verification procedure. The ROs, under the direction of Senior Reactor Operator (SRO) A, initiated the performance of OP/0/A/1105/09, Enclosure 4.11, "Control Rod Patch Verification At Power". This procedure has the operator transfer each rod individually from its normal power supply to the auxiliary power supply, insert the rod approximately two percent, observe that plant computer position indications change for that rod, compare the computer identification point numbers for the changing indication with those documented by I&E procedure to be associated with that rod, and transfer power to the rod back to the normal power supply. The process is repeated for all control rods in a group. When all rods in that group have been checked, the entire group is withdrawn to the OUT LIMIT. The procedure is performed for all control rod groups.

Reactor Operators A and B successfully performed this procedure for groups 1 through 4. However, problems occurred with Group 5 following individual rod checks on that group. After transferring the rods back to their normal power supply, operators withdrew group 5 rods until the OUT LIMIT indication was received. An OUT LIMIT stops all further rod withdrawal in that group and is initiated when the first rod in the group reaches its individual out limit. When the OUT LIMIT was reached, it was noticed that not all rods in the group were at 100 percent withdrawn. When the rods were moved individually during the patch test, there had been a slight difference in the amount of rod insertion. When the group was withdrawn, a rod which had not been inserted quite as far as the others reached its out limit prior to the other rods reaching 100 percent withdrawn. The operators had to clear the group OUT LIMIT and realign the rods at less than 100 percent withdrawn by transferring each rod individually to the auxiliary power supply and inserting it slightly. This was performed for the first eleven rods.

As the auxiliary power supply was transferred to Rod 12 of Group 5, RO A received the expected indications for this configuration: the TRANSFER CONFIRM lamp was on, the CONTROL ON lamp for Group 5 was on, the CONTROL ON lamp for rod 12 was on, and the CONTROL ON lamp for the other rods in Group 5 were extinguished. When RO A began inserting rod 12 at 1506 hours, all Group 5 rods fell into the core. Reactor power fell to 30 percent full power within three seconds. Reactor Coolant System (RCS)[EIIS:AC] pressure and temperature dropped due to the rapid reduction in reactor power. A reactor trip from 30 percent power occurred when three of the four Reactor Protection System (RPS) [EIIS:JC] channels reached their pressure/temperature trip setpoint at 1506.44 hours, approximately three seconds after the rod group drop. All remaining control rods dropped into the core.

RO A had decided to manually trip the reactor when he saw the indications of the dropped rod group but he was unable to do this prior to the automatic trip. RO A placed the ICS Feedwater Master and Steam Generator-Reactor Master control stations in automatic to allow the feedwater system to receive the normal post-trip runback signal.

Post-trip response was mostly as expected. Pressurizer level decreased to 70 inches, then rose and stabilized at 106 inches. RCS pressure dropped to 1833 psig, then increased and controlled at 2134 psig. RCS Hot and Cold Leg temperatures converged and stabilized at approximately 555 degrees F. Steam generator levels dropped to and controlled at the normal low level setpoint of 25 inches on the startup range. Steam generator pressures peaked at 1054 psig, then dropped and controlled at approximately 970 psig. Although steam generator pressure was stabilized, it was noticed that one of the four turbine bypass valves (TBV) [EIIS:SO], MS-19, was controlling erratically. The valve demand signal was oscillating when near the closed position.

CRD AC Breaker 10 required 68 milliseconds following the reactor trip signal to open. Post-trip review criteria requires breakers to operate within 80 milliseconds. It is desired to have them operate within 60 milliseconds. Maintenance Engineering was notified in writing of the slightly long trip time.

RPS Channel A did not trip. Work request 33200C was written to investigate. The trip setpoints for all four RPS channels were checked and they were all found to be within tolerance. Channel A was found to be calibrated toward the lower tolerance limit, while the other three channels were calibrated toward the upper tolerance limit.

Main Steam Relief Valves (MSRV) relieved for approximately ten minutes after the reactor trip. After dispatching an operator to the MSRVs, it was found that three of the sixteen MSRVs had not reseated. RO A decreased turbine header setpoint which closed the three unseated MSRVs. The last MSRV to reseat did so at a pressure of 990 psig. This is within the tolerance of the range established by Maintenance procedures. Approximately two hours after the reactor trip RO A was instructed to take the Turbine Bypass Valve control stations to manual by SRO A per the trip recovery procedure. This was done to prevent the TBV setpoint from changing to a lower value when the control rod breakers were reset. The lower setpoint would lead to an RCS cooldown. As this action was being performed, SRO B was on the telephone to the Radwaste Supervisor, whose office is near the MSRVs. SRO B heard the sound of an MSRV relieving over the telephone. He informed the Operations Shift Supervisor who proceeded with a radio to the MSRVs. The Shift Supervisor saw one relief valve actuate and then reseat a few seconds later. This occurred two more times. RO A was attempting to control steam generator pressure manually. However, the same erratic automatic control problems also occurred with manual control. The correct valve position for the pressure at which RO A was attempting to control was slightly off the closed position. As valve MS-19

opened off its seat, valve position indication would swing up quickly, When the valve was closed, steam generator pressure increased. RO A attempted to control under these conditions for approximately three minutes. When it was obvious that manual control was not adequate, turbine header pressure setpoint was increased and the turbine bypass valves returned to automatic control. Work request 33205C was written to investigate the poor control of MS-19. Investigation showed that the valve was sticking approximately one inch off its seat and that the valve stem had a gummy residue on it. Adjustments were made to the controller to offset this problem and produce less erratic valve movement. The valve response was more stable after these adjustments were made.

An inspection of the Turbine Building found indications that a water hammer (a sudden acceleration of water through a pipe which challenges piping restraints) had occurred on a Main Steam [EIIS:SO] line from the turbine bypass valve outlet header to the condenser, Numerous hangers were bent and damaged. A guard rail near the Turbine Bypass Valve discharge line was found deformed and nearby scaffolding was damaged.

At approximately 1715 hours, radiation monitor (RIA) 3RIA-54 [EIIS:IL], Turbine Building Sump Monitor came into alarm. SRO A directed a non-licensed operator to open the Turbine Building Sump pump breakers. A Turbine Building sump sample request was initiated to batch release [EIIS:WD] the contents of the sump. The sample results were less than minimum detectable activity. No other indications of primary to secondary leakage were present. RIA-40, Condensate Steam Air Ejector monitor [EIIS:IL], did not alarm, nor did RIA-16 and 17, Main Steam line monitors [EIIS:IL]. The operators did not notice any abnormal control of steam generator level or feedwater flow during the transient.

Work request 33202C was generated to investigate the cause of the rod group drop. I&E personnel inspected the Motor Power Signal Assembly of the Group 5 power supply. This assembly contains lights which indicate the phases currently energized by that power supply. They found four phases energized. Since the programmers for this power supply only energize a maximum of three phases at any time during normal rod movement, the I&E technicians suspected that the normal and auxiliary power supplies were connected. Transfer switch number 38, which was used to transfer power supplies for rod 12 of group 5, was found to have failed to completely transfer. This switch was replaced. The failed transfer switch was given to the Control Rod Drive System Manager for inspection.

Inspection of the failed transfer switch showed that the "make before break" contacts had stopped in the "make" position. The switch has seven sets of contacts arranged along the axis of a common rotating shaft. Each set of contacts consists of connecting posts to a common neutral, the auxiliary power supply, and the normal power supply. Another contact which rotates with the shaft is electrically connected to the common supply and contacts either the normal or auxiliary power supply posts. When a signal is given for a power supply transfer, the shaft is rotated by a pulse to

its driving solenoid. The rotating contact briefly touches both power supply posts before rotating to a position where it is only contacting the new power supply post. The rotational arc is limited by a ratchet mechanism. Since the contact sets are all driven by the same shaft, all sets transfer at the same time. Six of the seven sets of contacts correspond to the six phases of the CRDM. The seventh energizes the TRANSFER CONFIRM lamp on the CRD panel. The TRANSFER CONFIRM signal is energized when the auxiliary power supply is energized and deenergizes when the auxiliary supply is deenergized. Inspection found that the rotating contact had mechanically bound in a position where it was contacting both auxiliary and normal power supply connections.

Unit 3 was stabilized at hot shutdown conditions with Operations personnel safely controlling the reactor after the trip. No Engineered Safeguards Systems [EIIS:JE] or pressurizer relief valve actuation occurred, and no noticeable increases in RCS leakage were introduced.

CONCLUSIONS

After attempting to transfer the power supplies of Group 5 from its normal to auxiliary power supply, RO A began to move Rod 12 of Group 5. As he did so, all rods in group 5 dropped into the core. The reactor tripped from 30 percent full power three seconds later due to variable low pressure-temperature trip. The cause of the rod group drop was a failure to transfer normal and auxiliary power supplies on rod 12. This caused both of these power supplies to be electrically connected through the rod 12 transfer switch. The auxiliary power supply logic was therefore superimposed on the normal power supply logic for all rods in group 5. The normal power supply kept two phases of each CRDM in that group energized, since no rod motion signal was present. When the CRD rod motion signal was delivered to the auxiliary power supply, it began sequentially energizing the CRDM phases of all the Group 5 rods. When two phases energized by the auxiliary power supply became aligned opposite the two phases energized by the normal power supply, the magnetic fields generated effectively canceled each other, resulting in the dropped rods.

The transfer switch was found in a partially transferred position. Inspection showed that the rotating contacts had stuck against the auxiliary power contact post while still connected to the normal power supply post. The root cause is assigned equipment failure of the Electro Switch model 87907A-S rotary switch and is NPRDS reportable. The exact cause of the contacts binding is not known but several avenues of investigation are being pursued.

The Control Rod Drive System Manager noted that there were two types of switches present in the transfer cabinets. Most of the switches appeared to be identical. However, a few switches had noticeably larger insulating plates separating the contact sets, including the failed Group 5, Rod 12 switch. The transfer switches on each unit were inspected. It was found

that of the 207 total switches at Oconee, six large-plate switches have been installed: one on Unit 1, two on Unit 2, and three on Unit 3.

Warehouse supplies were checked and it was found that the different style switches have the same manufacturer and model number, are packaged in identical containers, and are stored in the same warehouse location. A review of the purchase order history of these transfer switches shows that they have not been purchased since the establishment of the purchase order database in 1981. It is believed that the small-plate transfer switches were part of the original installation. The large-plate transfer switches may have been a later substitution by the manufacturer, which were subsequently ordered as spare parts. Both types of switches were disassembled and inspected to determine what other differences might exist. No obvious differences could be found. Other than the size of the insulating plates, the switches appeared to be identical in every respect. Further inquiries are being made to the manufacturer, Electro Switch, Inc.

A review of events over the past two years has shown that Unit 3 tripped following a dropped control rod group (Group 6) on January 19, 1990 and also on November 13, 1990. The first event was reported under Licensee Event Report (LER) 287/90-01. The rod group fell into the core when transferring power supplies during a prerequisite test to a monthly rod movement test. The cause of that trip was listed as unknown. It now appears that this trip was caused by a similar failure of a transfer switch to completely transfer. A failure of the transfer switch for Group 6 Rod 6 occurred while patch verification testing was taking place during the last Unit 3 refueling outage. The switch was replaced with a large-plate type at that time. It was realized that this had caused the earlier rod group failure and reactor trip. However, since there was no previous history of the transfer switches failing in this manner, the occurrence was considered an isolated event and no long term corrective actions were taken. A revision to LER 287/90-01 will be submitted. Since Unit 3 has tripped twice from the same cause in less than two years, this is classified as a recurring event. Corrective actions from the first event did not prevent the further events because the failure mechanism was not identified at that time.

The reactor trip on November 13, 1990 (LER 287/90-03) occurred due to a programmer equipment failure in the group 7 power supply. The power supply failed during normal operation and group 7 rods dropped into the core. The reactor was manually tripped. This event did not involve power supply transfer operations.

A Babcock and Wilcox representative who was involved with the original installation of the control rod drive system was consulted. He stated that the original switches were production tested following assembly. There were several failures associated with them during this testing but the failed switches were replaced at that time. The switch manufacturer's literature maintains that many aspects of switch performance improves with use, since the contact surfaces wear slightly and there is less friction during the transfer. It is possible that the failure rate for both the older, small-

plate type and the newer, large-plate type is the same, but that the defective older switches were weeded out by production testing. Functional testing is performed after installation of new switches. However, this testing may not be equivalent to the production testing. It may be necessary to more rigorously test all new switches prior to installation.

The operator does not have a positive indication when a transfer switch fails as it did in this event. The TRANSFER CONFIRM light was illuminated because the auxiliary power supply contact on the transfer switch was made. Positive indication could be achieved by changes to the circuitry. This is being evaluated.

The Reactor Protective System (RPS) tripped the reactor within three seconds of the dropped rod group. The failure of RPS Channel A to trip is attributed to the calibration tolerance of that channel. The other three channels reached their pressure/temperature setpoints earlier because they were at the upper end of their tolerance band. This caused the reactor trip prior to Channel A reaching its setpoint at the lower end of its tolerance band. RCS pressure/temperature ratio did not reach the RPS Channel A setpoint.

The erratic control of the turbine bypass valve (TBV), MS-19, was caused by a buildup of a gummy substance on the valve stem. A short term solution was to change the controller setpoints on the TBV demand station so that the two TBVs that are controlled from that station acted in unison. This stabilized steam generator pressure. The work request for repair of this valve was left open to clean the valve stem and determine the source of the residue (possibly heated lubricant) when the valve is able to be isolated. The erratic nature of the TBV control led to the inadvertent cycling of one of the main steam relief valves when the TBV demand station was placed in manual control. Reactor Operator (RO) A was unable to control steam generator pressure in manual with the conditions as they existed prior to the MS-19 repair. The appropriate action, to adjust setpoint and return to automatic control, was taken.

A water hammer occurred on the TBV discharge header following the trip. Evidence of a water hammer had been found on a previous Unit 3 trip on the same discharge line. It was found at that time that an orifice in a line which normally routed condensation to the condenser was clogged. As a result, a modification was performed on December 15, 1989 which rerouted the piping to a point on the TBV discharge header where existing pumping traps could pump the water to the condenser. Three trips since the installation of this modification have not caused TBV discharge header water hammers. This is the first reactor trip since the installation of that modification that has produced a water hammer. On June 5, 1991 a temporary modification was installed to route condensate valve seat leakage to the TBV discharge header pipe which discharges to the B condenser section. The elevation of this piping is such that leakage introduced in the piping routed to the B condenser section could flow by gravity to the low point on the piping routed to the A condenser section instead of

directly to the condenser. A low point in the line to the A condenser section could collect water if leakage through the condensate valves is high. The low point has a drain line which routes the water to the condenser, but this line may not have the capacity to remove leakage past both the Turbine Bypass Valves and the flow from the condensate leakage. When the Turbine Bypass Valves opened, the water which had collected at the low point in the A condenser section line was accelerated into the piping. As a corrective action, the condensate leakage was subsequently routed directly to the Turbine Building sump.

On July 3, 1991, Unit 3 tripped due to an unrelated problem. Inspection of the Turbine Building after this trip showed no indications of a water hammer.

It is concluded that the water hammer was due to an inadequate design and review of the temporary modification. Project Engineer A, who prepared the modification package, and the Operations Superintendent discussed the possibility of backflow to the piping leading to the A condenser section. However, it was decided that the probability of water collecting at the low point was negligible. The modification was therefore approved and installed.

Indications of contamination of the Turbine Building basement sump were present. The proper precautions to stop releases from the sump by opening the pump breakers was taken until a sample could be analyzed for radioactivity. Samples showed no radioactivity above minimum detectable activity was present in the sump.

No personnel injuries were involved in this event. There was no release of radioactive materials or personnel overexposures involved.

CORRECTIVE ACTIONS

Immediate

1. Operations personnel safely controlled the reactor after the trip.

Subsequent

1. Work requests were prepared to replace the failed transfer switch, repair the erratically controlling Turbine Bypass Valve, repair water hammer damage, and investigate the cause of RPS Channel A not tripping.

2. The patch verification test was completed prior to subsequent startup.

3. A post-trip review and transient analysis was performed resulting in restart of the unit on June 10, 1991 at 0630.

4. Routing of condensate system leakage was changed from the turbine bypass valve discharge header to the turbine building sump.

Planned

1. Procedures associated with the Control Rod Drive movement periodic test will be changed to provide the reactor operator more positive indication that power supply changes have been made.

2. Instrument and Electrical (I&E) personnel will evaluate the need to test stock transfer switches prior to installation.

3. Investigation into the source of the large-plate style switches will continue and I&E will use the results of that investigation to evaluate whether replacement of these types of switches is warranted.

4. Licensee Event Report 287/90-01 will be revised to reflect the changes in root cause determined from this event.

5. Training packages covering the cause of the water hammer and the incorrect review of the Temporary Modification which routed the condensate system leakage will be prepared. They will be distributed to those personnel in the Projects group responsible for

preparation and review of this type of modification.

6. A station problem report will be initiated which suggest changes in the Control Rod Drive Mechanism (CRDM) power supply transfer scheme which will give the reactor operator a positive indication when power supplies fail to transfer. This problem report will go through the normal review process to have the change implemented as a Nuclear Station Modification.

SAFETY ANALYSIS

The plant response to this event was normal and as expected. No Engineered Safeguards system or emergency feedwater actuations were either required or received.

Three Reactor Protective System (RPS) channels tripped the reactor on pressure/temperature ratio. The fourth channel was found to be at the lower limit of its tolerance band and the other three at the high end of their tolerance band. Therefore the fourth RPS channel did not actuate. Operations personnel maintained all parameters within nominal post-trip values. Integrated Control System stations were placed in automatic to allow an automatic feedwater runback. Specifically, Reactor Coolant System (RCS) pressure dropped to a low of approximately 1833 psig following the trip, and then increased and controlled at 2134 psig. Pressurizer level fell to a minimum of 70 inches before being controlled at approximately 106 inches. RCS temperatures converged and stabilized at approximately 555

degrees F. Main steam pressure increased to 1054 psig. Turbine bypass valves opened to lower steam pressure to approximately 970 psig. Feedwater flow decreased to control steam generator levels at a minimum level of 25 inches on the startup range.

A problem with turbine bypass valve control led to the inadvertent opening of a Main Steam Relief Valve approximately two hours after the reactor trip but the problem was mitigated and the relief valve reseated.

The Final Safety Analysis Report (FSAR) sections 4.5.3, 7.6 and 15.7 contain analysis of a single dropped rod. The Nuclear Engineering Support Section of Duke Power Design Engineering generally feels that the dropping of a group of rods, while not specifically analyzed in the FSAR, would make it very difficult for the unit to successfully run back to a lower power level and not trip. Reactor power tilt/imbalance related problems due to multiple dropped rods from one group should be less significant than the consequences of a single rod drop due to the distribution of the group rods in the core. A manual or automatic trip would terminate the initial transient and prevent the reactor from exceeding design parameters. Station Operating Procedures require the immediate manual trip of the reactor if more than one control rod drops. In this event, the RPS system tripped the reactor three seconds after the rod group drop. The reactor operator had diagnosed the problem and was about to manually trip the reactor when the automatic trip occurred.

Although no personnel injuries occurred as a result of this event, the water hammer which occurred in the turbine bypass valve discharge line could have potentially caused such injury if personnel were working near the lines.

There were no releases of radioactive materials or excessive exposures to radiation associated with this event. The health and safety of the public was not endangered.

ATTACHMENT 1 TO 9108280249 PAGE 1 OF 1

Duke Power Company (803)885-3000
Oconee Nuclear Station
P.O Box 1439
Seneca, SC 29679

DUKE POWER

August 15, 1991

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
LER 287/91-06, Revision 1

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report (LER) 287/91-06, Revision 1 concerning a unit trip. This supplement is to provide the NPRDS codes that were omitted from the original report.

This report is being submitted in accordance with 10 CFR 50.73 (a)(2)(iv). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

H. B. Barron
Station Manager

RSM/ftr

Attachment

xc: Mr. S. D. Ebneter INPO Records Center
Regional Administrator, Region II Suite 1500
U.S. Nuclear Regulatory Commission 1100 Circle 75 Parkway
101 Marietta St., NW, Suite 2900 Atlanta, Georgia 30339
Atlanta, Georgia 30323

Mr. L. A. Wiens M&M Nuclear Consultants
Office of Nuclear Reactor 1221 Avenue of the Americas
Regulation New York, NY 10020
U.S. Nuclear Regulatory Commission
Washington, DC 20555

NRC Resident Inspector
Oconee Nuclear Station

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